S
655.772
M26mit
1976

MONTANA INTERNATIONAL

TRADE COMMISSION

COAL GASIFICATION

FEASIBILITY STUDY

STATE DOCUMENTS COLLECTION

MAR 1 2 2001

MONTANA STATE LIBRARY
1515 E. 6th AVE.
HELENA, MONTANA 59620

LUMMUS

8-3223

MONTANA STATE LIBRARY
3 0864 0015 6858 6

LUMMUS

THE LUMMUS COMPANY

MONTANA INTERNATIONAL TRADE COMMISSION

COAL GASIFICATION
FEASIBILITY STUDY

8-3223
August, 1976

WIN96-60568

TABLE OF CONTENTS

I. INTRODUCTION

II. SUMMARY

III. SCOPE OF WORK

IV. PLANT ECONOMICS

a. Plant Cost
b. Operating Data
c. Personnel Requirements
d. Project Schedule

V. OVERALL PLANT DESCRIPTION

VI. PLANT DEFINITION

VII. ENVIRONMENTAL CONSIDERATIONS

VIII. APPENDIX

I. INTRODUCTION

This report covers the technical and economic definition of a coal gasification plant to produce 150 MM SCFD of pipeline-quality gas and 1000 ST/D of anhydrous ammonia. The conceptual design of this plant is based on the Lurgi coal gasification process and the use of Montana lignite. This study was prepared at the request of the Montana International Trade Commission as part of an overall Montana coal gasification study.

Digitized by the Internet Archive
in 2016

https://archive.org/details/montanainternati1976mont

II. SUMMARY

In recognition of a potential shortage of natural gas in Montana, the Montana International Trade Commission has undertaken an analysis of possible steps that can be taken to alleviate a limited supply of natural gas. One part of this overall program involves the production of pipeline gas and synthetic ammonia through means of demonstrated and available technology. The Lummus Company was requested to submit information for a coal gasification plant conceptually designed to produce 150 MM SCFD of pipeline-quality gas and 1000 ST/D of anhydrous ammonia.

The site of the facility is assumed to be in Montana near the coal mining facilities and in an area that has adequate water supply from the Missouri River. The technical definition of the coal gasification plant is based on the report of American Lurgi, Reference No. KGD-00-0791, dated June, 1976 and transmitted to Lummus on June 21, 1976. Lummus technology was used to convert raw synthesis gas to anhydrous ammonia and in the design of the utility systems required for this plant.

Using in-house data developed by Lummus from similar studies made for other organizations, Lummus estimates that the total installed cost of the plant will be about $552 MM. The cost is an order of magnitude estimate, and it has to be recognized that an accurate assessment of the cost of these facilities will require a considerable design investigating effort and is, of course, subject to changes outside the control of Lummus. In the body of the report, a breakdown of various segments of the plant is given.

In order to enable the Montana International Trade Commission to develop production cost of ammonia and SNG, significant data have been presented relating to operating requirements of this plant.

The study describes a complete grass roots plant processing run-of-mine coal similar to North Dakota lignite. An analysis of Montana lignite was not given to Lummus, and any changes from the assumed value in the coal may have to be evaluated if the concept of this plant is to be developed in further detail.

The product gas obtained from the process unit is available at about 400 psig and is compressed and delivered to the property limits of the plant at an assumed delivery pressure of 1000 psig into an assumed gas transmission pipeline. It has also been assumed that water will be available from the Missouri River to satisfy the requirements for cooling and process water. The plant is conceived to include all other facilities necessary for a self-sustaining operation, such as coal handling and processing, steam generation, cooling water towers, buildings, and storage facilities. It has been assumed that electrical power requirements for the plant will be supplied by the local utility company.

II. SUMMARY - cont'd

The plant has been developed on the basis of minimizing electrical power requirements and generating sufficient quantities of steam to provide energy for compressors through the application of steam turbines. In this initial phase, it has been assumed that coal fines obtained from the coal preparation area will be used as fuel to the boilers, and liquid hydrocarbon by-products would be available for sale.

Attempts have been made to include a variety of systems to treat both liquid and gaseous effluents to meet environmental regulations. This particular segment of the plant will require significant investigation together with the Montana State bodies that are concerned with the protection of the environment.

To assist the Montana International Trade Commission in its plans, Lummus has included a project schedule which shows the various tasks that have to be undertaken to define, engineer, and construct the facilities. On the assumption that a forward program can evolve, it is estimated that the time required for engineering, procurement, construction, and initial operations of the plant will be about seven years.

III. SCOPE OF STUDY

The purpose of this study is to evaluate the feasibility of installing a facility to produce 150 MM SCFD of pipe-line quality gas and 1000 ST/D of ammonia by coal gasification using Lurgi technology.

The following elements were included in the study:

1. Plant definition and distribution of process units and offsites.

2. Process block flow diagram and material balance.

3. Plant energy balance.

4. Operating requirements including consumption of raw materials, electric power, catalyst and chemicals and personnel requirements.

5. Capital cost estimates of process units and offsites.

6. Overall plant layout and space requirements for process units and offsites.

7. Environmental considerations.

IV. PLANT ECONOMICS

Economic data developed for this plant include plant total installed cost (TIC), raw materials, utilities, catalyst and chemicals consumptions, and personnel requirements. In addition, a project schedule showing the relative time durations of major engineering, procurement and start-up activities from the time of contract award, has been included.

a. Total Installed Cost

The total installed cost was estimated at $551.7 MM. This figure was developed from in-house data used in previous studies. All materials costs used in developing this estimate represent July 1976 costs. In developing this estimate it was also assumed that electric power will be supplied from a nearby utility and that the jobsite is near residential communities, thereby eliminating the need for a construction camp. A breakdown of the cost of the individual processing units and offsites is given in table 1.

Estimate of Total Installed Cost (TIC) of Plant

TABLE 1

Area	Description	Total, $M
1100	Gasification	86,500
1200	Shift Conversion	12,700
1300	SNG Gas Cooling	7,500
1310	NH_3 Gas Cooling	3,100
1400	Rectisol	43,200
1600	Phenosolvan & NH_3 Recovery	25,200
1700	Methanation	21,300
1800	Gas Liquor Separation	8,300
1900	Product Gas Compression & Drying	9,600
2000	Coal Preparation & Handling	46,500
3000	Air Separation Unit	50,500
3100	N_2 Compression & Liquid N_2 Wash	7,200
3200	NH_3 Synthesis Loop	23,300
3300	NH_3 Refrigeration	300
4000	Sulfur Recovery	16,200
5000	Steam Generation & Distribution	89,300
5200	Stack Gas Scrubbing	22,600
5400	Raw Water Supply & Treating	14,700
5500	Cooling Water	11,900
5600	Fire Protection System	900
5700	Miscellaneous Utilities	900
6000	Offsite Storage and Loading Facilities	4,900
7000	Plant Interconnecting Piping	10,000
8100	Liquid Waste Effluent System	4,700
8200	Ash Disposal	3,300
8300	Flare System	2,800
	SUBTOTAL	527,400
	Site Development	11,100
	Buildings	8,400
	Freight	4,800
	TOTAL BASIC PLANT COST	551,700

IV. PLANT ECONOMICS - Cont'd

b. Operating Data

Plant operating data includes the consumption of raw materials, utilities, catalyst and chemicals. A table summarizing products and by-products, available for sale or for use as fuel within the plant is also included.

In preparing the plant operating requirements, it was assumed that 4874 ST/day of coal fines generated during coal preparation would be sufficient to satisfy fuel requirements for steam generation of 67.2×10^9 Btu/day, while process by-products would be available for export. These by-products shown in Table 2 have a total fuel value of 29.1×10^9 Btu/day. As an alternate, one might consider using them to satisfy part of the boiler fuel requirements, and using 2763 ST/day of coal fines to meet the balance of 38.1×10^9 Btu/day. Coal fines in excess of this tonnage would be exported in lieu of the hydrocarbon by-products.

Consumptions of raw materials, utilities catalyst and chemicals shown below were developed by prorating in-house design data. Catalysts and chemicals costs shown are based on 1976 prices.

TABLE 2

Operating Data

Consumption of Coal & Utilities		
Coal to Plant (as received)		
Coal to Gasification	17,551	ST/day
Coal fines to steam-generation	4,874	ST/day
TOTAL	22,425	ST/day
Electric Power	58,000	KWH/hr
Raw Water	6,080	GPM
Consumption of Catalysts & Chemicals		
Shift Catalyst (assuming 4 yr. life)	$ 440	/day
Methanation Catalyst (assuming 2 yr. life)	$2,065	/day
Ammonia Synthesis Catalyst (assuming 3 yr. life)	$ 160	/day
Methanol (100%)	38,000	lbs/day
Phenosolvan Solvent (di-isopropylether)	3,060	lbs/day
Stretford Solution Chemicals	$2,160	/day
Water Treating Chemicals	$1,160	/day
Products and By-Products	**Per Stream Day**	
SNG @ 957 BTU/SCF	150	MM SCF
Fuel Gas @ 508 BTU/SCF	8.6	MM SCF
Naphtha (123,000 BTU/Gal)	17,840	Gal.
Tar Oil (133,000 BTU/Gal)	27,440	Gal.
Tar (147,000 BTU/Gal)	106,990	Gal.
Crude Phenols (122,000 BTU/Gal)	25,880	Gal.
Anhydrous Ammonia	1,107	ST
Sulfur	73	LT
Sulfuric Acid	110	ST

IV. PLANT ECONOMICS - Cont'd

c. Personnel Requirements

Plant operations, administration and maintenance personnel requirements were estimated based on in-house plant staffing information.

TABLE 3

Personnel Requirements

Operations and Administration

	No. of Personnel	Total Annual Salary
Plant Manager	1	$ 42,000
Assistant Plant Manager	1	33,000
Superintendents	3	90,000
Supervisors	50	1,150,000
Engineers	34	680,000
Foremen	6	99,000
Operators, Lab Tech.	250	3,300,000
Clerical	33	297,000
		$5,691,000
Add 30% for Overhead		1,707,300
		$7,398,300

Maintenance

Superintendents	1	30,000
Supervisors	9	207,000
Engineers	9	180,000
Foremen	32	528,000
Craftsmen, Helpers, Laborers	275	3,630,000
Clerical	6	54,000
		$4,629,000
Add 30% for Overhead		1,388,700
		$6,017,700

IV. PLANT ECONOMICS - Cont'd

d. PROJECT SCHEDULE

The project schedule delineates the major activities and their time relations required to complete the project.

The schedule takes into account the present market conditions and delivery of equipment and materials.

In the development of this schedule certain parameters were analyzed in order to arrive at the start of gas production date of November 1982, with complete on stream operation by September 1983. In principle, the schedule has tried to minimize the financial risks by deferring extensive procurement activities until after regulatory approval is received. However, certain critical equipment such as draglines may need to be requisitioned prior to receipt of such approval.

Factors that have a direct impact on the proposed schedule are as follows:

1. Delivery of draglines.

2. Starting date and duration of Lurgi detailed engineering data.

3. Approval from regulatory agencies.

4. Delivery of major equipment and materials.

The schedule is based on selecting a contractor by January 1, 1977. Approval from regulatory agencies is anticipated by January 1979, and start of construction is scheduled at the same time.

Delivery of equipment and commodities will begin in 1980 and continue until mid 1982. Plant areas will be turned over for precommissioning beginning in March 1981 and continuing through 1982. Start of gasification and gas production is scheduled for November 1982, and continuing until full gas production rate is achieved in September 1983.

AMC

ACTIVITY 21-32	DESCRIPTION
01	CONTRACTOR SELECTION
02	
03	PHASE I
04	SITE INVESTIGATION & SELECTION
05	
06	RECEIVE LURGI DATA FOR PRELIMINARY
07	FEASIBILITY STUDY
08	
09	PREPARE PRELIMINARY DESIGN
10	
11	PREPARE PRELIMINARY ESTIMATES
12	
13	SUBMIT PRELIMINARY FEASIBILITY REPORT
14	
15	RECEIVE FINAL LURGI DATA FOR FEASIBILITY REPORT
16	
17	PREPARE DESIGN OF DOWNSTREAM PROCESS UNITS
18	UTILITIES AND AUXILIARY FACILITIES
19	
20	PREPARE ESTIMATE
21	
22	PREPARE PROJECT SCHEDULE
23	
24	PREPARE FEASIBILITY REPORT
25	
26	SUBMIT FEASIBILITY REPORT
27	
28	ASSIST CLIENT IN PREPARING APPLICATION TO
29	REGULATORY AGENCIES
30	
31	FILE APPLICATIONS TO REGULATORY AGENCIES
33	
33	PHASE II
34	PREPARE FINAL PROCESS DESIGN AND EQUIPMENT
35	SPECIFICATIONS
36	
37	COMPLETE ARRANGEMENT DRAWINGS AND ENGINEERING
38	SPECIFICATIONS
39	
40	OBTAIN FIRM COMPETITIVE QUOTATIONS
41	
42	COMMIT ORDERS FOR CRITICAL EQUIPMENT
43	
44	ENGINEERING FOR REFINED ESTIMATES
45	
46	PREPARE REFINED ESTIMATES
47	
48	SUBMIT REFINED ESTIMATE
49	
50	ANTICIPATED APPROVAL FROM REGULATORY AGENCIES
51	
52	PHASE III
53	DETAILED ENGINEERING DESIGN
54	
55	PROCUREMENT
56	
57	MATERIAL AT SITE
58	
59	SITE WORK
60	
61	CONSTRUCTION
62	
63	OPERATOR TRAINING
64	
65	START-UP ASSISTANCE
66	
67	FULL OPERATION
68	
69	CRITICAL EQUIPMENT
70	DRAG LINE #1, #2, & #3
71	LOADING SHOVEL #1 #2, & #3
72	GASIFIERS
73	MAJ. TURBINE DRIVES & COMPRESSORS
74	COAL FIRED BOILERS
75	OXYGEN PLANT GOLD BOX
76	
98	TOTAL THIS PAGE
99	TOTAL

MONTHS

1977 1978 1979 1980 1981 1982 1983 1984

1st delv. drag line

2nd delv. drag line

3rd delv. drag line

#1 #2 #3

first gas

full gas production

LEGEND

——— - ACTIVITY DURATION ▱ - DELIVERY AT SITE

R - ISSUE FOR INQUIRY ⊘ KEY MILESTONE DATE

▲ - ISSUE FOR PURCHASE

LUMMUS

JOB. NO. 8-3223 (8-12)

DATE ISSUED JULY 23, 1976

REPORT AS OF JULY 23, 1976

COAL GASIFICATION FEASIBILITY STUDY
FOR
MONTANA INTERNATIONAL TRADE COMMISSION

AREA (13-17) PAGE 1 OF 1 (18-20)

FORM 102 0511 30

V. OVERALL PLANT DESCRIPTION

The Coal Gasification Plant to be located in Montana is a grass roots plant and includes all process systems, utility and environmental support facilities, tankage, buildings, and electric power generating facilities. The complex will produce 150 MM SCFD of synthetic pipeline gas and 1,000 ST/D of anhydrous ammonia. The product SNG will have a minimum HHV of 957 BTU/SCF measured at 14.73 psia, 60°F, and dry basis.

The design is based on the Lurgi Pressure Gasification Process. Non-proprietary process units, offsites, sulfur recovery, and waste effluent control systems were designed by Lummus.

The Process Flow Diagram and Material Balance Sketch No. 1 shows the major processing areas. Sized coal is delivered to the gasifier feed system. The coal enters each gasifier through a lock-hopper system and passes downward while being gasified. Steam and oxygen are introduced at the bottom of the gasifier to effect the coal gasification reactions. A revolving grate supports the coal bed, cleans out the ash, and distributes the steam-oxygen mixture. The gasifier is designed to remove the ash as a solid particulate through an ash lock hopper. The ash is dumped into a hydraulic sluicing system and is conveyed to the ash handling area, where it is concentrated by mechanical means and is subsequently trucked to the mine for disposal.

The hot, crude product gas leaving the gasifier reactor is cleaned of tar and dust by cooling in quench vessels, steam generators, and coolers. The tar oil is recovered from the quench water. A portion of the crude gas is passed through shift conversion reactors.

The effluent leaving the shift converter is divided into two streams. The larger portion of the shift converter effluent is combined with the portion of the crude gas that bypassed the shift converters and is further processed for SNG production. The smaller portion of the shift converter effluent is further processed for ammonia production.

The combined gas stream that is used for SNG production is cooled through heat exchangers to recover sensible heat, additional oil, and naphtha.

V. OVERALL PLANT DESCRIPTION - cont'd

The gas stream, which consists of methane, ethane, hydrogen, hydrogen sulfide, carbon monoxide, carbon dioxide and nitrogen, is then purified of hydrogen sulfide and carbon dioxide. This is accomplished by absorption using cold methanol in the Rectisol unit. The purified gas is methanated to remove almost all the residual carbon monoxide and a portion of the carbon dioxide by reaction with hydrogen to produce methane. This raises the heating value so that the synthetic gas can be blended with natural gas. The product gas is dried and compressed for delivery to the pipeline.

The shift converter effluent gas used for ammonia production is also cooled in a parallel cooling train and then is purified of hydrogen sulfide and carbon dioxide in a separate two stage Rectisol system.

Leaving the second stage Rectisol unit, the process gas passes through a liquid nitrogen wash, where all the methane, ethylene, and ethane present are condensed, leaving only the hydrogen and nitrogen in the vapor state. The hydrogen/nitrogen mixture composition is adjusted with additional nitrogen to a 3:1 ratio and passes to the ammonia synthesis loop. The gas entering the synthesis loop is compressed, preheated, and catalytically converted to ammonia. The ammonia product is cooled and condensed for delivery to product storage.

The oxygen required for the gasifiers and the nitrogen required for the liquid nitrogen wash and ammonia synthesis is supplied from the self-contained air separation plant included in the complex.

The Stretford unit processes the carbon dioxide containing hydrogen sulfide from the Rectisol unit and converts the H_2S into saleable elemental sulfur in liquid form.

The production of SNG and ammonia from coal requires a steady supply of steam and electric power. High-pressure steam (1,500 psig) is generated in coal-fired boilers using coal fines obtained from the coal preparation section. Medium-pressure steam (550 psig) is produced in process waste heat boilers and from higher pressure steam let down through steam turbines. Electric power is supplied to the plant by a local utility company.

The complex is designed with maximum reliability built into the system to minimize the possibility of interruption in gas production. Independent, parallel processing systems are employed to minimize the effect of the loss of a process unit. In addition, spare equipment is provided at critical points. The process train philosophy is shown on the Process Train Arrangement Diagram shown in Sketch 5.

The environmental control systems are conceived to be integrated with the process units, waste heat recovery, cooling water, and ash handling systems. Wherever possible, water reuse was incorporated in the design.

V. OVERALL PLANT DESCRIPTION - cont'd

TABLE NO. 3 - ENERGY BALANCES

Approximate energy balances were calculated for the overall plant and the gasification section as follows:

OVERALL PLANT ENERGY BALANCE

Input	Quantity	10^9 BTU/D	HHV%
Coal to plant (35.02% moisture, 6.86% ash, and 6,894 BTU/lb HHV)	22,425 ST/D	309.2	98.5
Electric power consumption	58,000 KWH/HR	4.8	1.5
TOTAL INPUT		314.0	100.0
Output			
Pipeline-quality Gas (957 BTU/SCF HHV)	150 MM SCFD	143.5	45.7
Anhydrous Ammonia (9,800 BTU/lb HHV) (total produced)	1,107 ST/D	21.7	6.9
Fuel Gas (508 BTU/SCF HHV)	8.6 MM SCFD	4.4	1.4
Liquid By-products (tar, tar oil, naphtha, and phenols)		24.7	7.9
TOTAL OUTPUT		194.3	61.9

GASIFICATION ENERGY BALANCE

Input			
Coal to gasifiers (35.02% moisture, 6.86% ash, and 6,894 BTU/lb HHV)	17,551 ST/D	242.0	100.0
Output			
Pipeline-quality Gas (957 BTU/SCF HHV)	150 MM SCFD	143.5	59.3
Anhydrous Ammonia (9,800 BTU/lb. HHV) (total produced)	1,107 ST/D	21.7	9.0
Fuel Gas (508 BTU/SCF HHV)	8.6 MM SCFD	4.4	1.8
Tar (147,000 BTU/Gal)	106,990 Gal/D	15.7	6.5
Tar oil (133,000 BTU/Gal)	27,440 Gal/D	3.6	1.5
Naphtha (123,000 BTU/Gal)	17,840 Gal/D	2.2	.9
Crude Phenols (122,000 BTU/Gal)	25,880 Gal/D	3.2	1.3
TOTAL OUTPUT		194.3	80.3

VI. PLANT DEFINITION

The preliminary process design used for this study is based on processing lignite-type coal in an oxygen-blown LURGI pressure gasification system. The coal was assumed to gasify similarly to North Dakota lignite.

The Plant Elements forming the basis of this study and estimate are listed below:

Area	Description
1100	Gasification
1200	Shift Conversion
1300	SNG Gas Cooling
1310	NH_3 Gas Cooling
1400	SNG Rectisol and Refrigeration
1410	NH_3 Rectisol and Refrigeration
1420	Final CO_2 Wash (2nd Stage Rectisol) and Refrigeration
1600	Phenosolvan and Ammonia Recovery
1700	Methanation
1800	Gas Liquor Separation
1900	Product Gas Compression and Drying
2000	Coal Preparation and Handling
3000	Air Separation Unit
3100	Nitrogen Compression and Liquid Nitrogen Wash
3200	Ammonia Synthesis Loop
3300	Ammonia Refrigeration
4000	Sulfur Recovery
5000	Steam Generation and Distribution
5200	Stack Gas Scrubbing
5300	Power Distribution
5400	Raw Water Supply and Treating

VI. PLANT DEFINITION - Cont'd

Area	Description
5500	Cooling Water
5600	Fire Protection System
5700	Miscellaneous Utilities
6000	Offsite Storage and Loading Facilities
7000	Plant Interconnecting Piping
8100	Liquid Waste Effluent System
8200	Ash Disposal
8300	Flare System

VI. PLANT DEFINITION - Cont'd

A brief description of each area follows below:

Area 1100 - Gasification

The coal is gasified using a multiple train of LURGI pressure gasifiers. High-pressure oxygen and superheated steam are passed in countercurrent flow through a moving bed of coal, resulting in nearly complete conversion of the coal to gaseous compounds, some of which are subsequently condensed and processed in the liquid state.

Sized coal is conveyed from the coal storage to coal bunkers located above the gasifiers. Coal is charged to gasifiers through automatically operated coal locks which are depressured before receiving coal from the bunkers. The lock gas from depressuring is recompressed and re-injected in the gas cooling unit.

After filling with coal, the coal lock is pressurized with crude gas from the gas cooling unit and is equalized with the pressure of the gasifier. The coal is then charged to the top of the coal bed in the gasifier.

The gasification agent consisting of a mixture of oxygen and superheated steam is introduced through a rotating grate below the ash bed at the bottom of the gasifier. Partial combustion of the coal with the oxygen supplies the heat necessary for the gasification reactions.

Besides the crude gas produced, the process yields tar, oil, naphtha, phenols, ammonia, and sulfur.

The ash produced is removed by the rotating grate and discharged through a semi-automatically operated ash lock into an ash chute. From the ash chute, the ash is quenched with water and transferred to ash disposal.

Steam is generated in the jacket of the gasifier from the combustion heat and acts to cool the inner wall of the gasifier. The steam passes through a knock-out drum and is returned directly to the gasifier, partially furnishing the steam required for gasification.

The hot crude gas leaving the gasifier is directly quenched in a wash cooler with recycled tarry gas liquor. Tarry gas liquor produced in excess of the recycle is sent to the gas liquor separation unit.

The crude gas freed from dust and heavy condensibles and saturated with steam is further cooled by generation of 100 psig steam in a waste heat exchanger. The crude gas is then divided, with a portion passing directly to the gas cooling unit and the remainder is routed to the shift conversion unit.

VI. PLANT DEFINITION - Cont'd

Area 1200 - Shift Conversion

The shift conversion unit is designed to produce hydrogen required to raise the H_2/CO ratio for purposes of SNG production and ammonia synthesis. This is accomplished through the "water gas shift" reaction carried out catalytically in the presence of steam, as follows:

$$CO + H_2O = CO_2 + H_2 + 16{,}538 \text{ Btu/lb. mole.}$$

Approximately half of the total crude gas is subjected to shift conversion, with the balance bypassed directly to the gas cooling unit.

The portion of the converted gas used for SNG production is mixed with the bypass stream and passed to the gas cooling unit where additional heavy hydrocarbons and unreacted steam are condensed.

The proportions of these two streams are adjusted to obtain the desired H_2/CO of 3/1 ratio required for methanation.

The portion of the converted gas used for ammonia synthesis flows to a separate parallel gas cooling unit.

Area 1300 & 1310 - Gas Cooling Units

The gas cooling units are designed to cool the raw gas from gasification and shift conversion to remove the heavier hydrocarbons and unreacted steam before low-temperature purification. The cooling scheme is arranged to recover and utilize as much of the process heat as is practical.

First the converted gas is cooled and compressed. Following compression, the gas is divided into two portions. One portion is used for SNG production and mixes with cooled crude gas that bypasses the shift converters. Then it is cooled further in Area 1300.

The other portion used for ammonia synthesis is cooled in a parallel gas cooling train, provided in area 1310.

Area 1400, 1410, & 1420 - Rectisol Units

The gas purification unit utilizes the Rectisol process to remove CO_2, sulfur compounds, and other impurities from the raw gas. Low-temperature methanol is utilized to absorb the carbon dioxide and sulfur compounds. Sulfur compounds are removed to a level of less than 0.1 ppm (by volume) so that the gas meets the composition requirements for methanation.

The crude gas stream leaving the gas cooling units is chilled before entering the prewash tower to recover naphtha and water. The naphtha-free gas then enters an absorber, where sulfur compounds and the bulk of the CO_2 are removed by a cold methanol wash. The acid gas streams that leave the Rectisol System are directed to the Stretford unit for conversion to elemental sulfur.

VI. PLANT DEFINTION - Cont'd

Areas 1400, 1410 & 1420 - Rectisol Units - Cont'd

In Area 1400, the CO_2 in the SNG process stream is removed to about 3.5 mol percent, which is a suitable level for methanation. Similarly, most of the CO_2 is removed from the NH_3 process stream in Area 1410. However, the process gas for ammonia synthesis, has to be essentially free of CO_2; therefore, another CO_2 wash stage has been added in Area 1420.

Area 1600 - Phenosolvan and Ammonia Recovery Units

The process water from the Gas Liquor Separation Unit, which is contaminated with phenols, ammonia, hydrogen sulfide, and carbon dioxide, is treated in the Phenosolvan Unit prior to use as make-up water in the process gas liquor cooling tower. Crude phenol and liquid anhydrous ammonia byproducts are produced.

The incoming process water is passed through gravel filters for removal of suspended matter and then through extractors, where an organic solvent is used to extract phenols. The organic solvent is distilled and separated from the phenol and recycled to the extractors for reuse. The crude phenol by-product is recovered and transferred to storage for subsequent sale.

After removal of all traces of solvent, the dephenolized process water is stripped in the deacidifier to remove dissolved carbon dioxide and hydrogen sulfide, which is processed in the sulfur recovery unit. The resultant process water is distilled to recover 25 percent aqua ammonia, which is further distilled to produce commercially pure anhydrous ammonia. The remaining process water is then utilized as cooling water makeup to the process water cooling tower.

Area 1700 - Methanation

The methanation unit converts low BTU synthesis gas to methane-rich high BTU gas by the following exothermic reactions:

$$CO + 3H_2 = CH_4 + H_2O + 94{,}250 \text{ BUT per lb. mole } CH_4$$

$$CO_2 + 4H_2 = CH_4 + 2H_2O + 77{,}700 \text{ BTU per lb. mole } CH_4$$

Other minor reactions which take place are the hydrogenation of ethylene to ethane and hydrocracking of ethane to methane.

Process gas leaving SNG Rectisol unit is heated and passed through a guard vessel containing zinc oxide for removal of trace sulfur compounds. The flow of the feed gas is proportioned between two catalytic reactor stages along with recycled, methanated effluent gas, which serves to dilute the gas thereby controlling the temperature rise across the reactors. The reactors are designed as fixed bed downflow units employing a pelleted reduced nickel-type catalyst.

The reaction heat is removed by generation of 600 psig steam in waste heat exchangers at the outlet from each reactor.

VI. PLANT DEFINITION - Cont'd

Area 1700 - Methanation - Cont'd

Net gas leaving the methanation synthesis loop is passed through the cleanup reactor to accomplish essentially complete conversion of carbon monoxide, and then it is cooled by successive heat exchange with boiler feed water, fresh feed gas, air, and cooling water. Water condensed from the gas is separated and forwarded for recovery as boiler feed water. The net product is sent to the gas compression unit.

Area 1800 - Gas Liquor Separation

The gas liquor contains tar, tar oil, naphtha, and dissolved compounds such as phenols, ammonia, carbon dioxide, and hydrogen sulfide. Tar is defined as a heavier-than-water organic liquid phase, while tar oil is the lighter-than-water organic liquid phase.

The gas liquor separation is designed to clean up tarry and oily gas liquors by separating the incoming streams into tar, tar oil, recycled gas liquor, and clarified aqueous liquor streams.

The gas liquor streams originating from the gasification, shift conversion, and gas cooling units are cooled, combined, and reduced in pressure. The liquor flows to a large separator from which tar is removed. Flash gases released from the gas liquor by pressure reduction are scrubbed to remove ammonia. The tar is retained to be used as fuel within the plant or for export. The net liquor flow is forwarded to a second separator, where tar oil is separated and removed. The gas liquor passes to a final separator where additional tar oil is removed and sent to storage along with tar oil from the second separator.

The aqueous stream from the final separator passes to intermediate tankage before being fed to the Phenosolvan Unit.

Area 1900 - Product Gas Compression and Drying

The product gas compression unit consists of two parallel centrifugal compressors driven by condensing steam turbines. Gas leaving the methanation unit is compressed in the first stage of the compressor and then cooled prior to removing water to pipleline gas specifications. Drying is accomplished in a dehydration step employing liquid triethylene glycol (TEG) as the desiccant. The incoming wet product gas flows upward countercurrently with TEG in the glycol absorber. The dried product gas leaves the top of the absorber with a residual moisture content of less than 5 lbs./MM SCF of gas and passes to the second stage of compression. The water-rich TEG leaving the absorber bottom is passed to the glycol regenerator, where TEG is stripped of its water by heating with a small stream of dried product gas. The lean TEG from the glycol regenerator is returned to the top of the glycol absorber.

The product gas is then compressed in the second compression stage to the required pipeline pressure.

VI. PLANT DEFINITION - cont'd

Area 2000 - Coal Storage and Preparation

Run-of-mine coal is delivered to the plant. After crushing and screening, the coal is delivered through a system of conveyors to the live storage pile having a storage capacity of about six days' production for the gasification plant. A dead storage pile is also provided with a capacity sufficient to ensure approximately 30 days' production requirements. From the live storage pile, the coal is fed continuously through screens to achieve the correct size distribution for gasification. Coal fines not suitable for gasification are routed to storage silos and are used as fuel in the high-pressure steam boilers.

Area 3000 - Air Separation Unit

The oxygen facilities are designed to provide about 4000 T/D of gaseous oxygen to the process plant with an oxygen purity of 98 percent.

Two parallel process trains are utilized, with each unit consisting of a turbine-driven axial/centrifugal compressor, air separation section (cold box), and a turbine-driven centrifugal compressor. The air compressor turbines are of the extraction/condensing type, utilizing 1500 psig, 900°F steam from battery limits. The total make-up steam required for the rest of the complex is extracted at 550 psig, with the remainder going to the surface condensing type utilizing 550 psig steam.

Gasifier startup air and air for general use within the plant is provided from the air compressors. Excess nitrogen from the air separation system is used for the liquid nitrogen wash unit, ammonia synthesis, and process plant inert gas system. Liquid nitrogen storage is provided to ensure availability or purge gas during a plant outage.

Unit control will be centralized and combined with the main plant control room.

Area 3100 - Nitrogen Compression and Liquid Nitrogen Wash

Ammonia synthesis gas from the final CO_2 removal step goes to the liquid N_2 wash system. This gas first enters the washing column through a coil submerged in the liquid bottoms product. Most hydrocarbons and CO present in this stream condense, and the remainder of the gas, rich in hydrogen, enters the tower where residual hydrocarbons and CO are dissolved into circulating liquid nitrogen. The condensed hydrocarbon stream, identified as the methane fraction is first expanded and heated and then combined with the main SNG process stream going to the methanation unit. The purified hydrogen stream exiting the column overhead is mixed with addtional nitrogen to yield a H_2/N_2 ratio of 3/1. This mixture is heated by the incoming nitrogen and feed gas entering the liquid N_2 wash system and then is sent to the ammonia synthesis loop.

Another tail gas stream, identified as the fuel gas fraction, leaves the bottom of the column. This stream is available for use as fuel after being expanded and heated by incoming nitrogen.

VI. PLANT DEFINITION - Cont'd

Area 3100 - Liquid N2 Wash and N2 Compression - Cont'd

Nitrogen leaving the air separation unit is compressed to about 400 psig and cooled by the synthesis gas and the two expanded tail gas streams. Liquid nitrogen leaving the last exchanger is split in two portions. One portion enters the top of the washing column and is used as the scrubbing medium, while the other portion bypasses the column and is expanded and mixed with the purified hydrogen stream overhead stream to a H_2/N_2 ratio of 3/1.

The isenthalpic expansion of the nitrogen stream and the two tail gas streams provide the refrigeration requirements of the liquid N2 wash system.

Area 3200 - Ammonia Synthesis Loop

The H_2/N_2 mixture leaving the liquid N_2 wash system is first compressed to synthesis loop pressure of 2600 psig and then catalytically converted to ammonia according to the following reaction:

$$N_2 + 3H_2 \rightleftharpoons 2NH_3$$

This reaction is highly exothermic, and heat is recovered from the product stream by generating 600 psig steam preheating boiler feed water and feed effluent heat exchange. Further cooling and condensation of the ammonia product is achieved in water-cooled exchangers and refrigeration.

Refrigeration is provided by evaporating ammonia product and by an absorption/refrigeration package unit using lithium bromide. This system is used because of the available large quantities of low-pressure steam generated in the gas cooling section of the plant.

Uncondensed, unreacted hydrogen/nitrogen mixture is recompressed and recycled to the reactor. Condensed ammonia product is sent to storage tanks.

Area 4000 - Sulfur Recovery

The sulfur in the coal feed to the gasification plant is recovered using technologies based on the characteristics of each sulfur-containing stream produced in the plant. The design of the sulfur recovery system is based on coal containing an average of 0.93 percent sulfur on a DAF basis.

Most of the sulfur in the coal feed to the gasifiers is converted to hydrogen sulfide, which is removed from the crude gasifier effluent in the Rectisol system as a combination of acid gas streams. The hydrogen sulfide is converted in a Stretford unit to saleable elemental sulfur in liquid form.

The sulfur in the coal fines used to fire the steam boilers is converted to SO_2 and is removed from the flue gas leaving the boilers in a system consisting of electrostatic precipitators and a Wellman-Lord stack gas scrubbing unit described in Area 5200.

VI. PLANT DEFINITION - Cont'd

Area 4000 - Sulfur Recovery - Cont'd

The SO_2 is further converted to sulfuric acid, as described below.

Stretford Unit

The Stretford process, licensed by the North West Gas Board of the British Gas Corporation, is used to recover elemental sulfur from the combined acid gas streams leaving the Rectisol system. The process, using a dilute aqueous solution containing Na_2CO_3 sodium meta-vanadate and anthraquinone disulfonic acid (ADA), operates in a continuous, regenerative fashion, as follows:

H_2S is absorbed from the gas by the alkaline carbonate solution forming HS^- ions. This is accomplished in a countercurrent open grid tower. The sulfide is oxidized to free sulfur by vanadate according to the reaction:

$$HS^- + 2V^{5+} \rightleftharpoons 2V^{4+} + S + H^+$$

This reaction proceeds during the absorption step and is completed in a holding vessel. The solution is regenerated by reoxidation of V^{4+} to V^{5+}. This is accomplished by sparging with air in a separate vessel with ADA acting as a catalyst for the reaction. The sulfur forming as a floating froth is separated from the solution and is processed to produce a saleable liquid sulfur by-product.

The Stretford process removes only sulfur in the form of H_2S. Other sulfur compounds such as COS, CS_2, and mercaptans are unaffected by the process. The sulfurous compounds are present only in small concentrations and are incinerated to SO_2 at the Thermal Generating Station. A small degree of oxidation of sulfides in solution to thiosulfate and sulfate occurs. These salts are non-regenerable and require a small liquid purge.

The unit is designed in two parallel trains, each with a nominal capacity of 50 percent.

SO2 Conversion

The SO_2 stream leaving the Wellman-Lord system described in Area 5200 flows to a catalytic converter, where conversion of sulfur dioxide to sulfur trioxide takes place over vanadium pentoxide catalyst according to the following reaction:

$$2SO_2 + O_2 \rightleftharpoons 2SO_3$$

VI. PLANT DEFINITION - Cont'd

Area 4000 - Sulfur Recovery - Cont'd

SO_2 Conversion - Cont'd

Sulfur trixoide leaving the converter flows to an absorption tower, where it is absorbed in a strong aqueous solution of sulfuric acid. Additional sulfuric acid, resulting in a higher H_2SO_4 concentration, is formed due to the following reaction:

$$SO_3 + H_2O \rightleftharpoons H_2SO_4$$

Dilution water is added to the H_2SO_4 circulation system to maintain a steady concentration level, and an acid slip stream withdrawn from the absorber overhead is sent to the H_2SO_4 product storage facilities.

Area 5000 - Steam Distribution

Steam generated at 1500 psig and 900°F is let down through extraction condensing turbines driving the air compressors in the air separation unit. The 550 psig steam for the air compressor turbines is combined with 600 psig steam generated in the methanation and ammonia synthesis loop waste heat boilers. This steam is supplied to the gasifiers and to turbine drivers fed from the 550 psig steam system. The oxygen, refrigeration, ammonia synthesis, nitrogen, and product gas compressor Turbines use 550 psig and 100 psig steam, discharging to condensers at 4" Hga.

Steam generated from waste heat in the gasification unit is fed to the 100 psig steam system. This steam is used for reboilers in the Phenosolvan, Rectisol, and Stretford units, steam jet air ejectors, lock gas compressors, converted gas booster compressor, and methanation recycle compressors. These turbines all exhaust to condensers at 4" Hga.

Steam generated from the heat recovered in the shift conversion waste heat boilers and some of the gas cooling waste heat boilers is fed to the 60 psig steam system. This steam is utilized as heat input to reboilers in the Phenosolvan and Rectisol areas and for steam tracing and tank heaters. Excess steam from the 60 psig steam system is let down into the 20 psig header. The remaining gas cooling waste heat boilers generate additional 20 psig steam to be used as heating steam for reboilers in the Phenosolvan, Rectisol, NH_3 refrigeration and stack gas scrubbing units, and for the plant deaerators.

Turbine condensate, condensate from the 20 psig and 60 psig steam levels, makeup water from battery limits, and 20 psig steam are mixed and deaerated in the MP deaerator. The MP boiler feed pumps provide feed water to the gasifier jackets and to the methanation waste heat boilers through process exchangers.

Low-pressure condensate, make-up from battery limits, blowdown water, and 20 psig steam are mixed and deaerated in the LP deaerator. The 100 psig boiler feed pumps take suction from the deaerator and pump the feed water through process exchangers to the gasification waste heat boilers. The LP boiler feed pumps take suction from the deaerator and provide feed water to the shift conversion and gas cooling waste heat boilers.

VI. PLANT DEFINITION - cont'd

Area 5000 - Steam Distribution - cont'd

Turbine condensate, condensate from the 600 psig and 100 psig levels, and 20 psig steam are mixed and deaerated in the HP deaerator. The HP boiler feed pumps take suction from the deaerator and provide feed water to the shift conversion and gas cooling waste heat boilers.

Turbine condensate, condensate from the 600 psig and 100 psig levels, and 20 psig steam are mixed and deaerated in the HP deaerator. The HP boiler feed pumps take suction from the deaerator and provide feed water to the HP steam generation system.

Area 5200 - Stack Gas Scrubbing

This study is based on using excess coal fines produced in the coal preparation area as fuel for generating the steam requirements of the complex.

The coal fines fired in the steam boilers contain .93 wt. percent sulfur on a DAF basis. This results in about 1.3 lbs. of sulfur dioxide in the flue gas per MM BTU (HHV) of coal fines fired. A portion of this flue gas is scrubbed by the Wellman-Lord SO_2 recovery system in order that the SO_2 emission level in the stack gas can be reduced to no more than 1.2 lbs. of SO_2 per MM BTU (HHV) of coal fines fired. This maximum SO_2 emission level is specified by the Federal Environmental Protection Agency.

The Wellman-Lord system employs a process which continuously absorbs and regenerates SO_2 using an aqueous solution of sodium sulfite and sodium bisulfite. The reactions are:

Absorption: $SO_2 + Na_2SO_3 + H_2O \rightleftharpoons 2NaHSO_3$

Regeneration: $2NaHSO_3 \rightleftharpoons Na_2SO_3 + SO_2 + H_2O$

The flue gas feed to the Wellman-Lord system flows upward in an SO_2 absorber against an aqueous solution of sodium sulfite. With SO_2 removed, the flue gas leaves the top of the absorber and is discharged to the stack.

Sodium bisulfite solution containing SO_2 exits from the absorber into a forced-circulation evaporator-crystallizer, which is heated by low-pressure exhaust steam. The SO_2 vapor from the evaporator-crystallizer is cooled to remove water and then is sent to the sulfur recovery area.

The sulfite crystallizes in the evaporator-crystallizer and changes the solution to a sulfite slurry. The slurry is passed to a dissolving tank, where sulfite crystals are re-dissolved by water from the SO_2 vapor. The resultant solution is used again in the SO_2 absorber.

A moderate amount of the circulating solution is oxidized to non-regenerable sulfate. To control the sulfate level, a small stream of the solution is purged from the system and sent to the deep well disposal system.

VI. PLANT DEFINITION - cont'd

Area 5300 - Power Distribution

A conventional 3-level distribution system for an estimated total requirement of 58,000 KW is included in the design.

Area 5400 - Raw Water Supply & Treating

Raw water is supplied at the Gasification Plant battery limits. The sequence of water treating steps and the interaction with the waste effluent steps are similar to those shown on Sketch No. 4, Water Management Diagram. The system was designed for maximum water reuse. Raw water is required for cooling tower and potable water makeup.

Area 5500 - Cooling Water

Three separate cooling towers are provided to handle the bulk of the plant heat rejection, as follows:

- Cooling tower using treated fresh water as makeup.

- Cooling tower using treated gas liquor (process water) from the Phenosolvan and Gas Liquor Stripping Unit as makeup.

- Separate cooling tower using treated fresh water for the oxygen plants in order to minimize the hazard associated with hydrocarbons entering this system.

Blowdown water from the process gas liquor cooling tower system will be disposed of, conforming to local environmental regulations.

Chemical feeding equipment will be provided to permit addition of water treating chemicals to all systems as required in order to adjust pH and inhibit corrosion, scale formation, and biological plant growth.

Area 5600 - Fire Protection System

The fire protection system consists of a fire water loop, chemical, and foam fire suppression equipment and mobile equipment.

Area 5700 - Miscellaneous Utilities

Potable Water

Water for the potable and sanitary use is supplied from the raw water treatment plant where it is filtered, chlorinated, and treated prior to distribution.

VI. PLANT DEFINITION - cont'd

Area 5700 - Miscellaneous Utilities - cont'd

Instrument Air, Plant Air, and Inert Gas

A plant air system is provided to supply compressed air at a nominal 100 psig pressure to shops and service outlets throughout the plant.

Plant air is normally supplied from the air separation plant main air compressors. During periods of total plant shutdown, motor-driven air compressors supply the plant air requirements. The system is complete with necessary after-coolers, air receivers, and distribution piping. All plant air will be dried.

An instrument air system is provided to supply clean, dry air for instrument operation.

Instrument air is supplied by oil-free, motor-driven compressors operating at a system pressure of 100 psig. The system is complete with dryers, air receivers, and distribution piping. To ensure maximum reliability during a power outage, these compressors are connected to the emergency power system.

An inert gas system is provided to supply dry nitrogen from the oxygen plant. In addition, a liquid nitrogen tank provided with vaporization facilities supplies nitrogen to the system during periods of oxygen plant outage.

Communications

The plant is provided with two communication systems. An in-plant dial telephone system is installed and operated by the telephone company in space provided by the plant. This arrangement avoids capital expenditure and hiring of specialized maintenance skills. The system is automatically monitored against failure to the degree that it is acceptable for fire reporting and thereby avoids the operation of a separate fire alarm system. The system is arranged to allow outside communication from designated telephones.

Operating communications throughout the plant to roving personnel and vehicles is by radio. Radio paging interconnected with the telephone system is included for contacting non-operating personnel when they are away from their normal stations.

Area 6000 - Offsite Storage and Loading Facilities

Storage facilities are included to store by-products in the plant. Storage for a number of raw materials for plant feed are also provided. A minimum of 15-days' storage supply is provided for most by-products and raw materials, except for the anhydrous ammonia storage tank, where 30-days' storage is provided. The anhydrous ammonia product is stored as a liquid at atmospheric pressure in a double-wall insulated tank with a vapor recovery refrigeration system.

Liquid elemental sulfur produced in the sulfur recovery plant is pumped from a heated sulfur pit included in the sulfur recovery unit to the stockpile area.

VI. PLANT DEFINITION - cont'd

Area 8100 - Liquid Waste Effluent System

The liquid waste effluent treatment system is designed to maximize water reuse. The only discharge of waste water from the plant is cooling tower blowdown going to disposal and the water associated with the ash handling facility returning to the mine. The effluent treatment scheme is similar to that shown on the Water Management Diagram Sketch No. 4.

The bulk of reusable water is derived from the gas liquor area. After most of the phenols are extracted and H_2S, CO_2, and NH_3 are stripped from this stream, the process condensate is used as make-up water for the process gas liquor cooling tower. The cooling tower also serves as an oxidation unit for reduction of biological and chemical oxygen demand.

The blowdown from the process gas liquor cooling tower will be pretreated and disposed of, conforming to local environmental regulations.

Area 8200 - Ash Disposal

Ash discharged from the gasifiers is quenched and sluiced by water to screw classifiers. The classifier discharge drops onto conveyors and is transferred to an ash bin, which is emptied into trucks for disposal in the mining area.

Area 8300 - Flare System

The flare system will be capable of flaring the total gasifier effluent in the event of power failure, steam system, or cooling water failure. A knock-out drum will be provided to collect any water and heavy hydrocarbons in the gasifier effluent that may condense en route to the flare. These liquids will be incinerated. The flare system may also be employed to flare product gas during plant startup when gas quality is below the acceptable specifications.

The flare system will collect all emergency and operating hydrocarbon vents and burn them at the top of a flare stack.

The self-supporting flare stack includes ignitor, flame front generators, molecular seal, and continuous burning pilots. Ladder and access platforms will be provided on the flare stack to facilitate maintenance.

VII. ENVIRONMENTAL CONSIDERATIONS

The environmental control systems integrated with the process units and the cooling water, steam generation, and ash handling systems are designed to meet applicable environmental standards and regulations.

Air Emission

Sulfur Dioxide Emission

The sulfur in the coal feed to the gasifiers and the steam boilers is recovered to a major extent. After being cleaned and cooled, the raw product gas is passed through a Stretford desulfurization system. Virtually all the hydrogen sulfide in the gas is converted to elemental sulfur and removed.

The flue gas from steam boilers is scrubbed in the Wellman-Lord SO_2 recovery system described in Area 5200. The coal fines fired in the boiler result in about 1.3 lbs. of SO_2 per MM BTU fired. The flue gas from the Wellman-Lord system contains less than 1.2 lbs. of SO_2 per MM BTU FIRED and is discharged to the stack.

Oxides of Nitrogen

The formation of oxides of nitrogen (NOx) depends on the size, type, and arrangement of burners, type of fuel, and the heat flux. The steam boilers will be designed to limit the NOx formation to a level below that permitted by the EPA.

Flare

Vent gas deriving from startup, emergency blowdown, and temporary local relief is sent via headers to an elevated flare system.

Particulates

The flue gas from the steam boilers will be passed through electrostatic precipitators, which will remove about 99 percent of the fly ash. Secondary cleaning and polishing are done in the Wellman-Lord system. The resulting particulate emission after the cleanup will be below the level permitted by the EPA.

Effluent Water Streams

Process and utility waste water will be reused within the plant to minimize discharge to the river.

The process gas liquor is treated to remove oils, phenols, ammonia, and hydrogen sulfide. The stripped gas liquor is then used as the make-up water for the process water cooling tower. The blowdown from this cooling tower is treated to remove suspended matter and is then sent to disposal. The blowdown

from the fresh water cooling tower is treated to remove any contaminants and may be reused in the humidifier section of the Wellman-Lord unit.

Solids Removal

Ash and other solid wastes will be sent to the mine. Certain aqueous waste streams could be disposed of with the ash. Ash leachability studies and methods of preventing contamination of water in nearby wells should be considered.

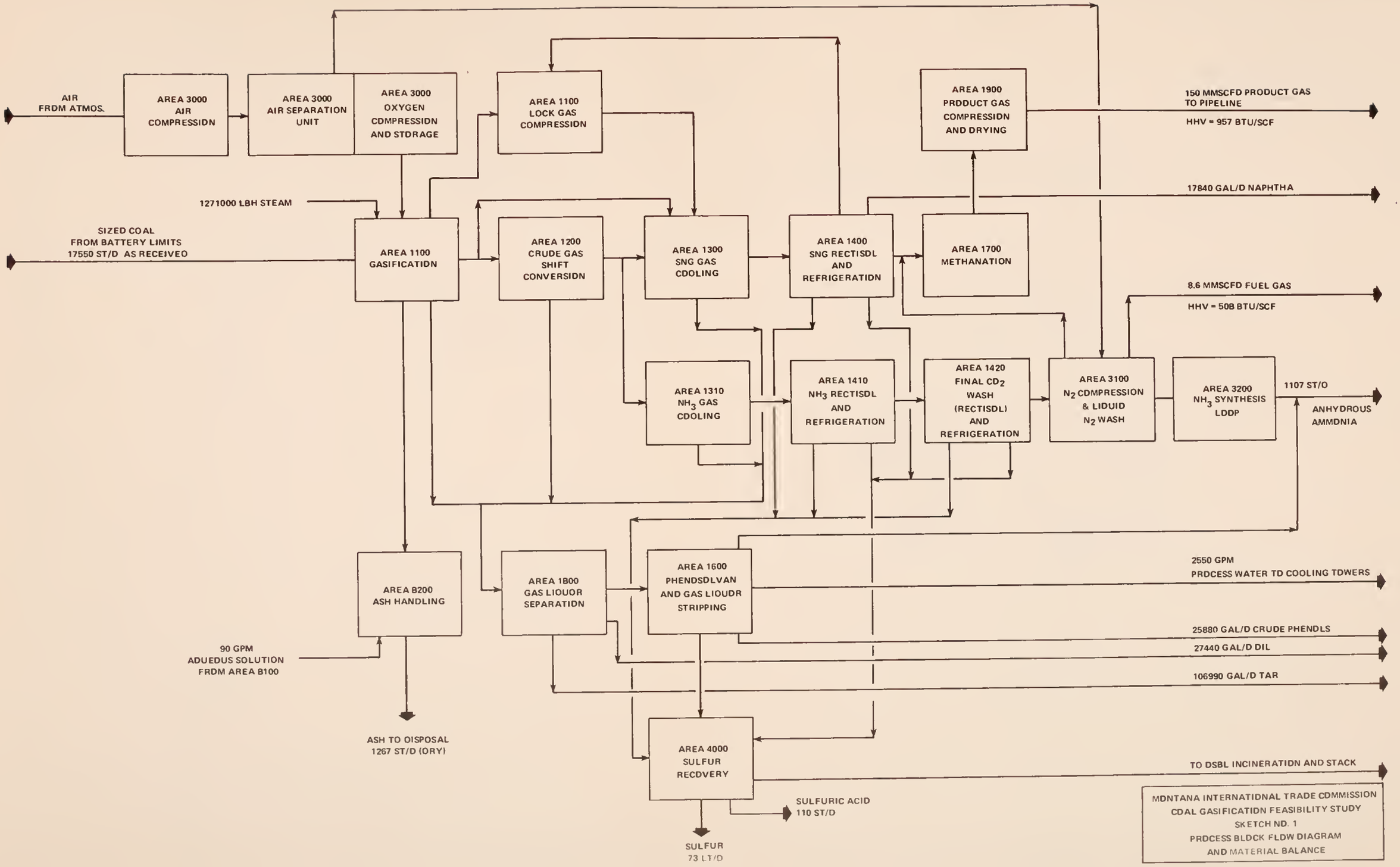
Socio-Economic Considerations

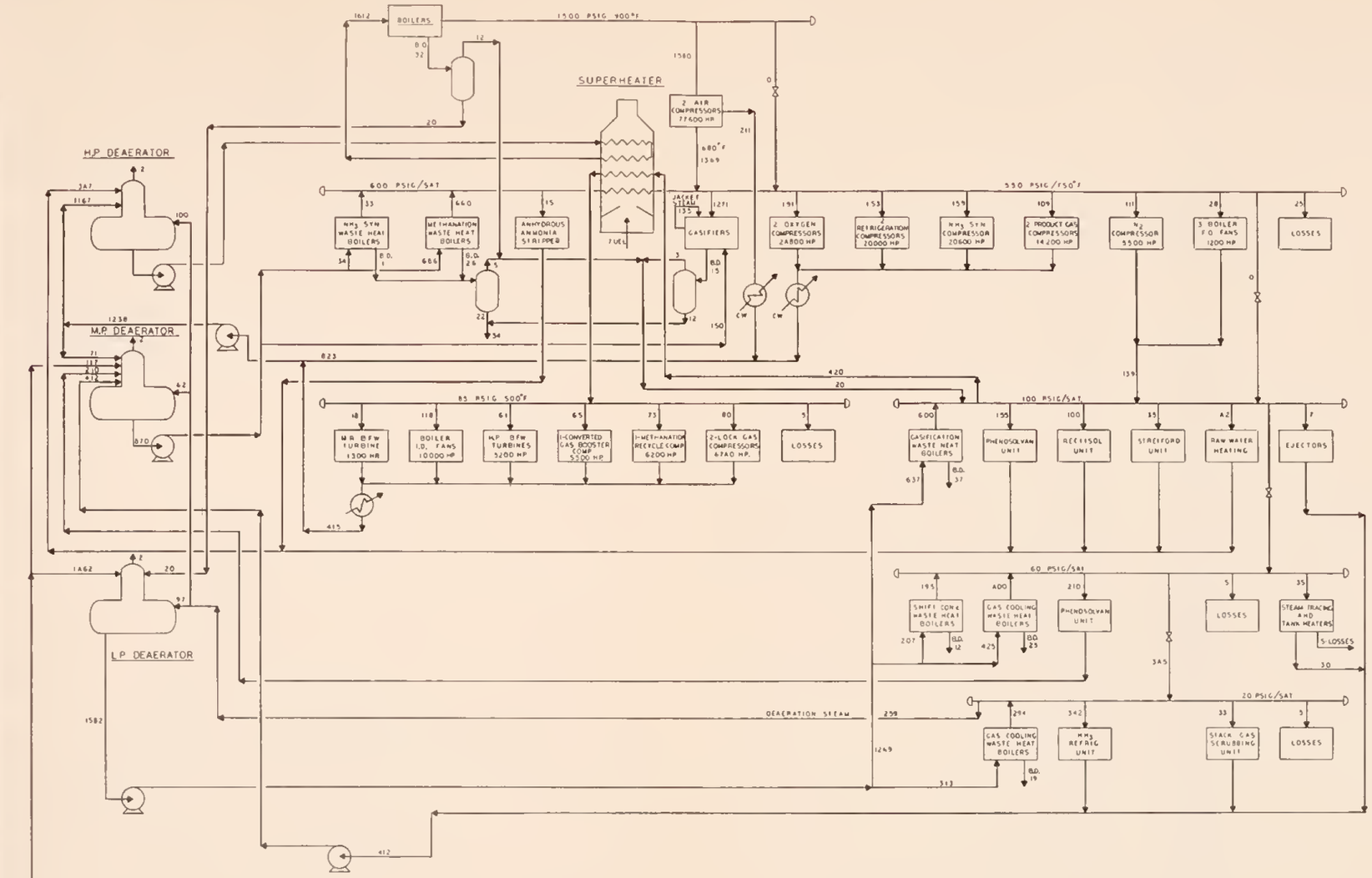
During the construction of the plant, a work force of some 2000-3000 people, not including support facilities, will be employed. The socio-economic and environmental impact of these people and the related housing, transportation, sanitary, recreational facilities, etc., must be taken into account.

VIII. APPENDIX

Sketches

NO. 1 -	Process Block Flow Diagram and Material Balance
NO. 2 -	Steam and Condensate Balance
NO. 3 -	Cooling Water Balance
NO. 4 -	Water Management Diagram
NO. 5 -	Process Train Arrangement Diagram
NO. 6 -	Overall Plant Layout and Space Requirements

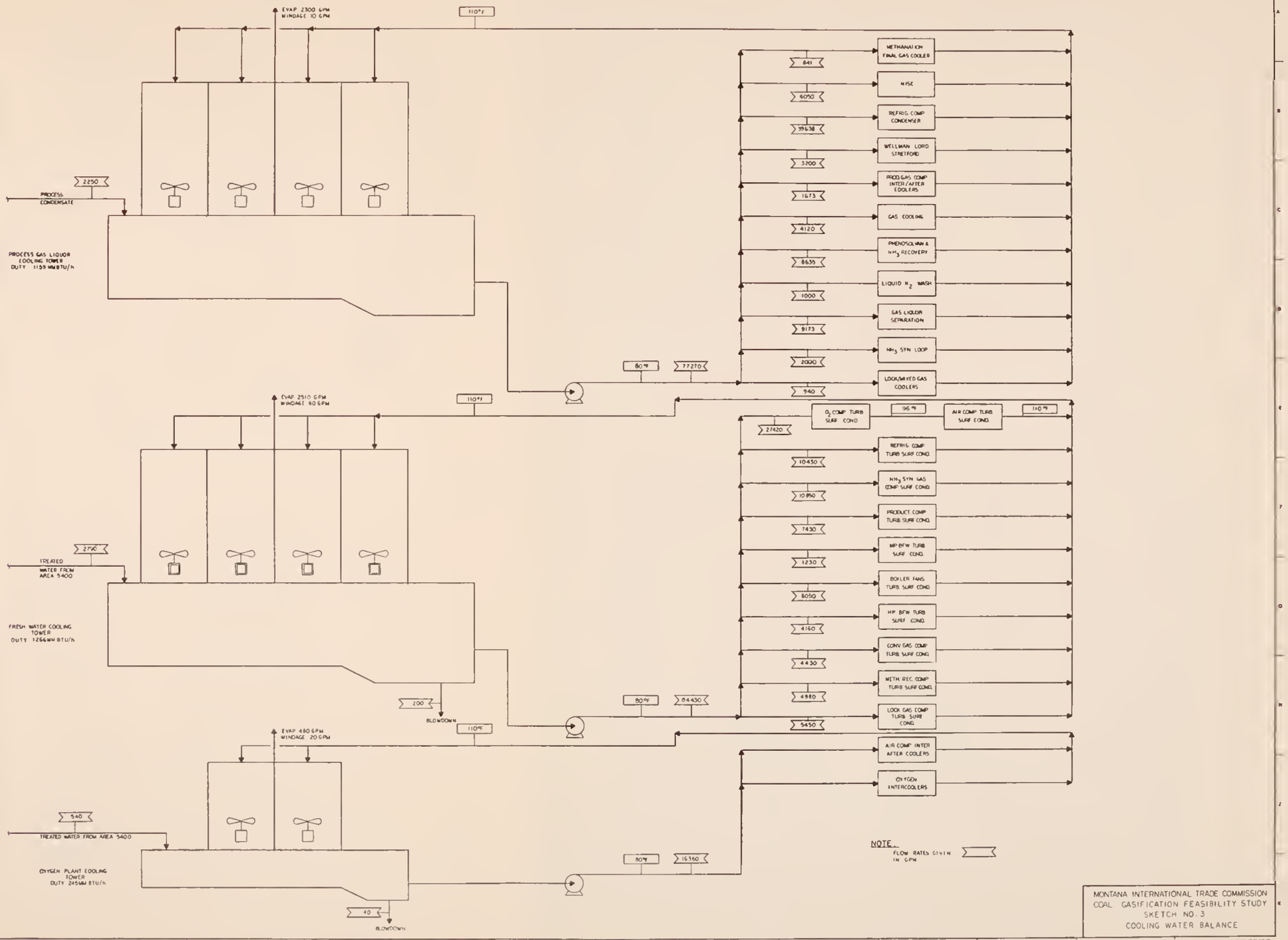

AIR
FROM ATMOS.
AREA 3000
AIR
COMPRESSION
AREA 3000
AIR SEPARATION
UNIT
AREA 3000
OXYGEN
COMPRESSION
AND STORAGE
AREA 1100
LOCK GAS
COMPRESSION
AREA 1900
PRODUCT GAS
COMPRESSION
AND DRYING
150 MMSCFD PRODUCT GAS
TO PIPELINE
HHV = 957 BTU/SCF
17840 GAL/D NAPHTHA
1271000 LBH STEAM
SIZED COAL
FROM BATTERY LIMITS
17550 ST/D AS RECEIVED
AREA 1100
GASIFICATION
AREA 1200
CRUDE GAS
SHIFT
CONVERSION
AREA 1300
SNG GAS
COOLING
AREA 1400
SNG RECTISOL
AND
REFRIGERATION
AREA 1700
METHANATION
8.6 MMSCFD FUEL GAS
HHV = 508 BTU/SCF
AREA 1310
NH_3 GAS
COOLING
AREA 1410
NH_3 RECTISOL
AND
REFRIGERATION
AREA 1420
FINAL CO_2
WASH
(RECTISOL)
AND
REFRIGERATION
AREA 3100
N_2 COMPRESSION
& LIQUID
N_2 WASH
AREA 3200
NH_3 SYNTHESIS
LOOP
1107 ST/D
ANHYDROUS
AMMONIA
AREA B200
ASH HANDLING
AREA 1800
GAS LIQUOR
SEPARATION
AREA 1600
PHENOSOLVAN
AND GAS LIQUOR
STRIPPING
2550 GPM
PROCESS WATER TO COOLING TOWERS
25880 GAL/D CRUDE PHENOLS
27440 GAL/D OIL
106990 GAL/D TAR
90 GPM
AQUEOUS SOLUTION
FROM AREA B100
ASH TO DISPOSAL
1267 ST/D (DRY)
AREA 4000
SULFUR
RECOVERY
TO OSBL INCINERATION AND STACK
SULFURIC ACID
110 ST/D
SULFUR
73 LT/D
MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 1
PROCESS BLOCK FLOW DIAGRAM
AND MATERIAL BALANCE

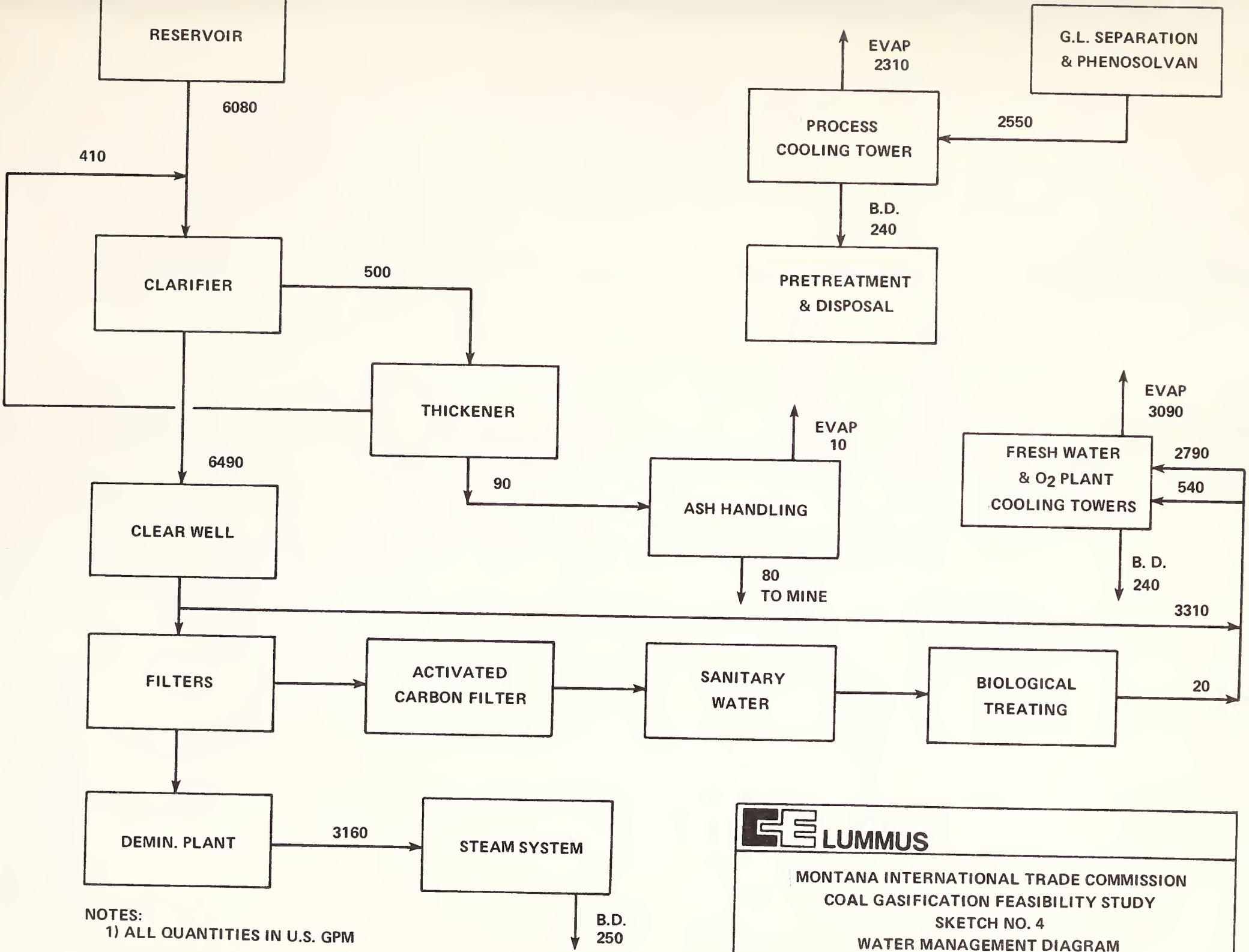


NOTES:

1. FLOW RATES GIVEN IN 1000 lbs/hr

MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 2
STEAM AND CONDENSATE BALANCE

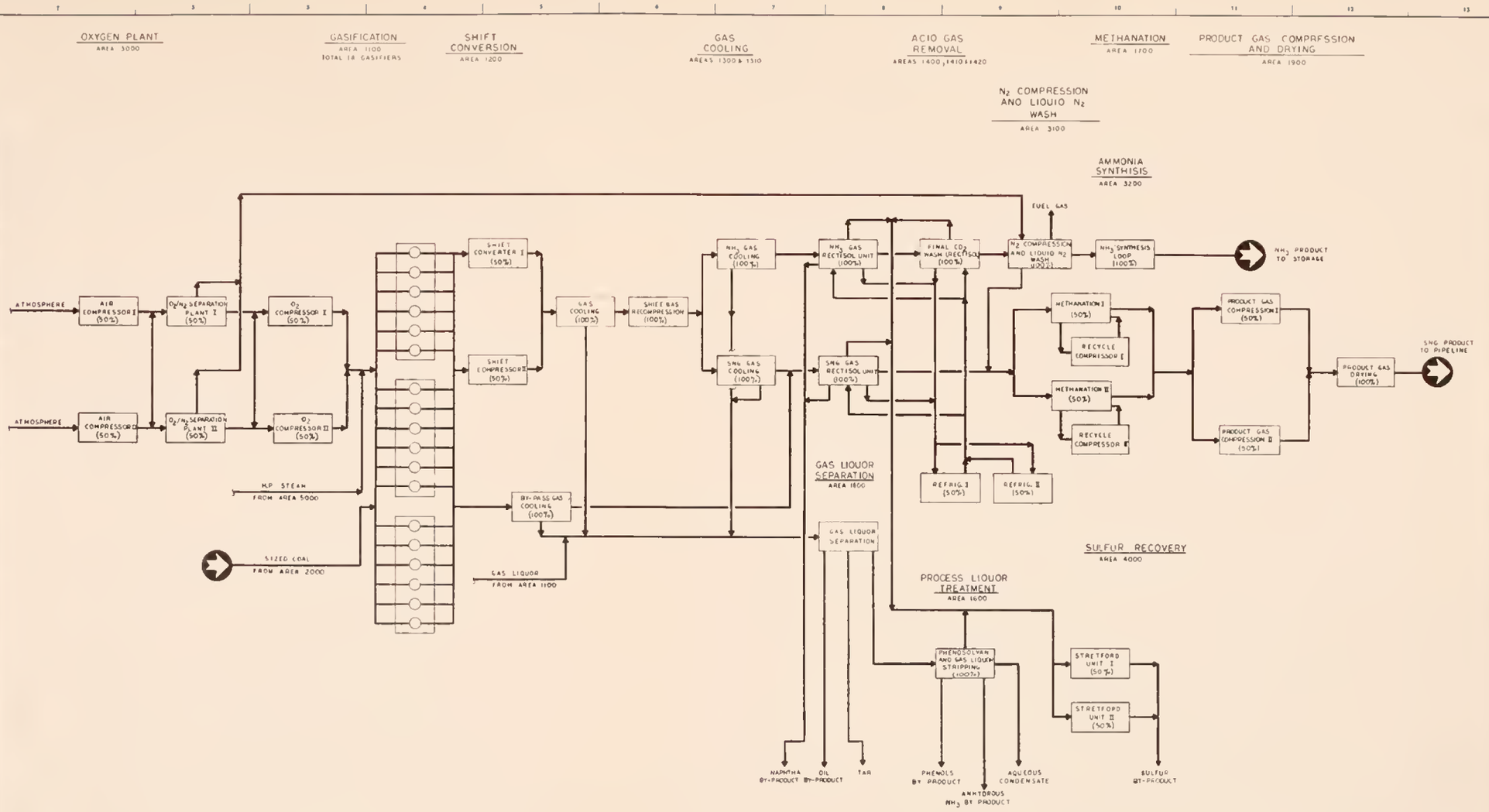

EVAP 2300 GPM
WINDAGE 10 GPM
110°F
2250
PROCESS CONDENSATE
PROCESS GAS LIQUOR COOLING TOWER
DUTY 1159 MM BTU/h
841
6050
39638
3200
1673
4120
8635
1000
9173
2000
940
METHANATION FINAL GAS COOLER
HYSC
REFRIG COMP CONDENSER
WELLMAN LORD STRETFORD
PROD GAS COMP INTER/AFTER COOLERS
GAS COOLING
PHENOSOLVAN & NH_3 RECOVERY
LIQUID N_2 WASH
GAS LIQUOR SEPARATION
NH_3 SYN LOOP
LOCK/MIXED GAS COOLERS
80°F
77270
EVAP 2510 GPM
WINDAGE 80 GPM
110°F
2750
TREATED WATER FROM AREA 5400
FRESH WATER COOLING TOWER
DUTY 1266 MM BTU/h
200
BLOWDOWN
O_2 COMP TURB SURF COND
96°F
AIR COMP TURB SURF COND
110°F
27420
10430
10850
7430
1230
8050
4160
4430
4980
5450
REFRIG COMP TURB SURF COND
NH_3 SYN GAS COMP SURF COND
PRODUCT COMP TURB SURF COND
MP BFW TURB SURF COND
BOILER FANS TURB SURF COND
HP BFW TURB SURF COND
CONV GAS COMP TURB SURF COND
METH REC COMP TURB SURF COND
LOCK GAS COMP TURB SURF COND
80°F
56430
EVAP 480 GPM
WINDAGE 20 GPM
110°F
540
TREATED WATER FROM AREA 5400
OXYGEN PLANT COOLING TOWER
DUTY 245 MM BTU/h
40
BLOWDOWN
AIR COMP INTER AFTER COOLERS
OXYGEN INTERCOOLERS
80°F
16360
NOTE.
FLOW RATES GIVEN IN GPM
MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 3
COOLING WATER BALANCE



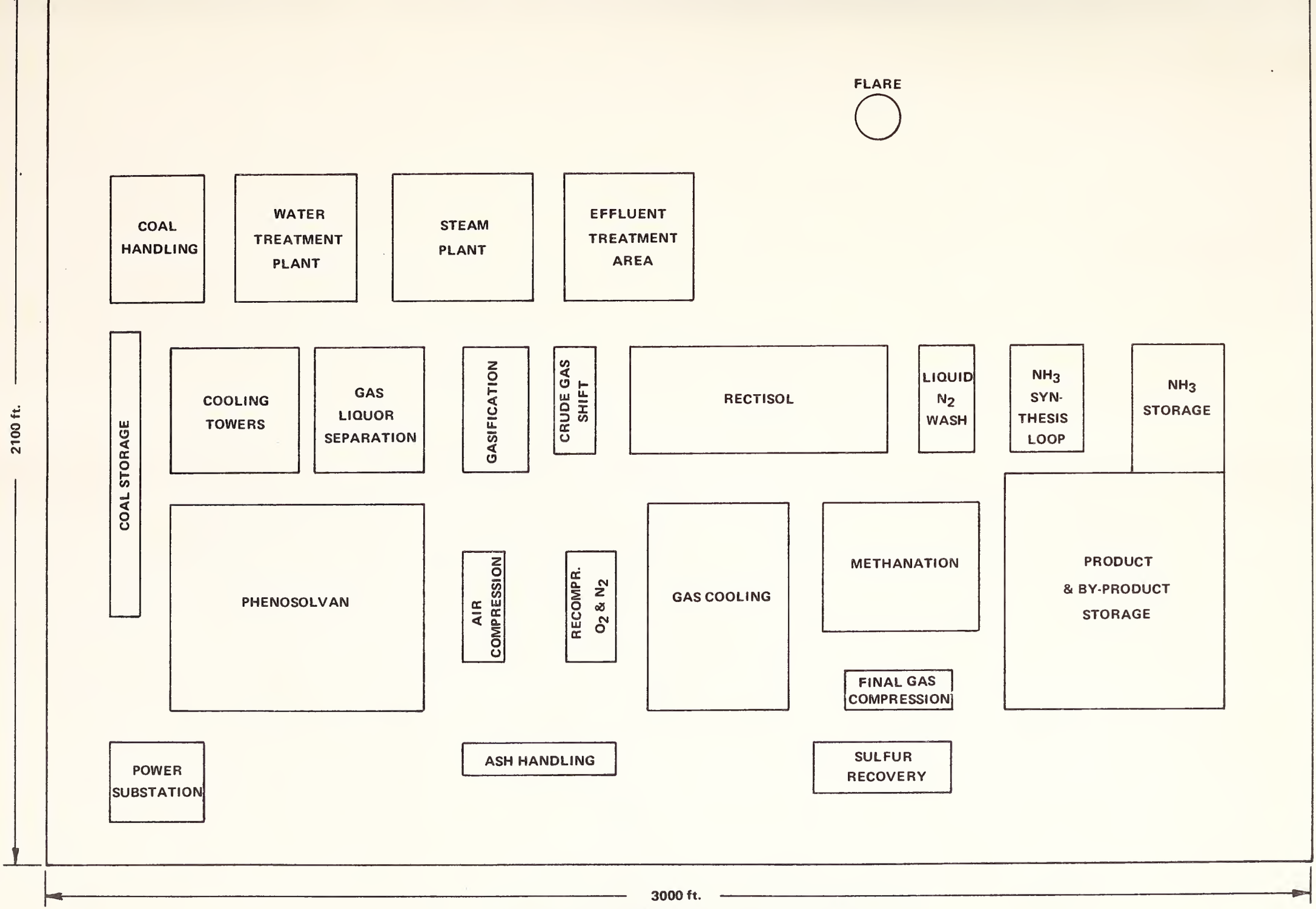
NOTES:
1) ALL QUANTITIES IN U.S. GPM

LUMMUS

MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 4
WATER MANAGEMENT DIAGRAM



MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH 5
PROCESS TRAIN ARRAINGMENT DIAGRAM



MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 6 - OVERALL PLANT LAYOUT AND SPACE REQUIREMENTS